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PROJECT NO. 48551

REVIEW OF SUMMER 2018	**§**	**PUBLIC UTILITY COMMISSION**
ERCOT MARKET PERFORMANCE	**§**	**OF TEXAS**

COMMENTS OF EXELON CORPORATION

William Berg
Vice President, Wholesale Market Development
Exelon Corporation
200 Exelon Way
Kennett Square, PA 19348
610-765-6660
William.berg@exeloncorp.com

Marka Shaw
Director, Wholesale Market Development
Exelon Corporation
1005 Congress Avenue
Austin, TX 78701
512-391-1962
Marka.shaw@exeloncorp.com

Cynthia Brady
Assistant General Counsel
Exelon Corporation
4300 Winfield Road
Warrenville, IL 60555
630-657-4449
Cynthia.brady@exeloncorp.com

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COMMENTS OF EXELON CORPORATION RESPONDING TO QUESTIONS 2-8

Exelon Corporation ("Exelon") provides the following to the specific questions posed by the Public Utilities Commission of Texas ("PUCT" or "Commission") Staff. The Commission Staff posed a number of questions to stakeholders, to be addressed by comment in two stages. In this second round of comments (addressing Questions 2-8), we move from analyzing the scarcity mechanism during the past summer, in general terms, to specific analysis of the ERCOT Capacity, Demand and Reserves ("CDR") and Seasonal Assessment of Resource Adequacy ("SARA") reports, the performance of particular types of resources, and a review of price formation on specifically identified peak days. Exelon's comments once again rely on analytics performed by The NorthBridge Group ("NorthBridge"), with an attached Appendix A providing further detail.

I. EXECUTIVE SUMMARY

Generator revenues under the current Operating Reserve Demand Curve ("ORDC") construct are insufficient to incent new thermal builds and to retain existing resources, both of which are necessary to achieve even the relatively low future reserve margins that are assumed within the CDR. But there is a path to improving resource adequacy both in the short-term and for the long-term, if the Commission acts before Summer 2019. Exelon's recommendation of a Loss of Load Probability ("LOLP") shift of at least one standard deviation is conservative in that it will maintain the reserve margin around 11%, while an LOLP shift of two standard deviations would provide even greater assurance for future resource adequacy over time, bringing future reserve margins closer to the level of reliability projected for the ORDC when it was first implemented. No matter what the Commission decides, there will be a cost. Under an LOLP shift, customers benefit from enhanced reliability from the investment that will result from scarcity pricing in a greater number of intervals. But there is a two-fold cost in doing nothing -- the financial cost that customers will incur as reserve margins dwindle and scarcity prices are

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triggered more frequently and at higher prices, as well as the additional cost in actual loss of load events due to inadequate resources on the system to support load growth.

The CDR and SARA are valuable tools in assessing near-term supply and demand fundamentals but are not designed to predict actual realized outcomes or ensure resource adequacy. There is nothing in the results of the Summer 2018 that invalidate the use of either the CDR or the SARA as important inputs in the evaluation of prompt or very near-term resource adequacy. In fact, the CDR and SARA 6-month and 3-month projections were close to actual Summer 2018 outcomes. However, the CDR and SARA cannot predict the weather or other random variables that may affect resources' availability in real-time. Additionally, the CDR and SARA reports are based on the best information currently available from resource owners regarding the future operation of existing generation, and planned generation that has taken certain steps in the interconnection process. But importantly, neither report incorporates an economic evaluation of whether current generators will actually remain online or whether planned generators will delay or cancel their entry.

As discussed in Exelon's September 14th comments, these economics depend on the real-time market and the forward market which is ultimately derived from and settled against the real-time market. Contrary to certain claims,[1] generators cannot make up revenue deficiencies from the scarcity pricing mechanism with revenues from day-ahead offers, bi-lateral contracts, futures transactions, and ancillaries services. All of those transactions are a derivative of the real-time market, and are ultimately settled against it. As such, all generator revenues ultimately are dependent upon real-time prices. Of course, the only revenues that are relevant to the discussion of a properly functioning wholesale market and resource adequacy are those of generators.[2]

The recently-released report by the Brattle Group on behalf of ERCOT, "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region,"

[1] Project 48551, Texas Industrial Energy Consumers' Comments ("TIEC"), and Texas Energy Association for Marketers' Response to Commission Staff Question Number One, September 14, 2018.

[2] To suggest that generators should rely on revenues from an affiliated retail supplier to make up for potential losses from the generation business unit, as TIEC implies in its Initial Comments, simply highlights the fact that the current construct is not sustainable. Moreover, even assuming that a generator is affiliated with a retail supplier (which is not necessarily the case), in order to "make up" the revenue lost on the generation, a retail supplier would need to approximately double the market price for power. Given the fierce competition between retail suppliers, which lowers prices, it is highly unlikely that retail prices would support generation investment.

("the Brattle Report")[3] does not justify a different conclusion. Based on an initial review, it appears that Brattle and ERCOT have made significant changes to their assumptions relative to prior studies regarding year-to-year weather volatility, forced outage rates, and intermittent resource output shape and volatility, that impact their results. Regardless of the changes in assumptions, the Brattle Report shows that relative to the analysis that Brattle performed for ERCOT at the inception of the ORDC, the market equilibrium reserve margin has decreased, and the loss of load expectation has increased, meaning that reliability has been degraded since the ORDC's adoption. Moreover, as the Brattle Report acknowledges, "[i]f investors have different beliefs about load and other factors affecting revenues, or if they face different costs, the market equilibrium reserve margin could differ from our estimates."[4]

In reality, investors and generators both have taken actions inconsistent with the assumptions in the Brattle Report. Exelon's September 14th comments showed the impact on the reserve margin if approximately 900 MW of existing resources disappear (roughly the amount of previously mothballed units that came back shortly before Summer 2018). Since that time, there have been a number of major developments impacting future resource adequacy that reinforce the points made in those comments and highlight the urgency of Commission action to implement an LOLP shift in the ORDC. Specifically, the owners of the 650 MW Oklaunion plant announced their plans to shut down the facility by October 2020, based on the fact that its continued operation in the ERCOT market is uneconomic.[5] In addition, the ERCOT GIS update released on October 1st reflects a number of cancellations of new-build thermal plants, totaling approximately 2,300 MW of capacity, of which approximately 1,800 was incorporated into the projected reserve margins from the most recent CDR report.[6] Taken together, these developments remove 1.4 GW of anticipated capacity for Summer 2020, rising to 2.4 GW of anticipated capacity by 2022, nearly 1/3 of all gas capacity that is in the queue. To put this into perspective using the CDR as a guidepost, by adjusting the most recent CDR for these changes, the projected reserve margins will fall below 10% starting in 2020 and will reach 7.55% by 2022.

[3] *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, Final Draft*, October 12, 2018.

[4] *Id.*, at 42.

[5] "AEP Announces closure of Oklaunion Coal Plant", *RTO Insider*, _September 24, 2018.

[6] *ERCOT Generator Interconnection Status Report*, September 2018 showing cancellations of Apex Bethel CAES, Indeck Wharton, Pinecrest G, and Panda Sherman 2 G.

These market participant actions highlight the fact that the current ORDC design does not produce sufficient net revenues to incent new entry and retain marginal existing resources, despite both types of capacity being needed to simply maintain reserve margins in the future. Because of this, the market is losing both existing and expected new entrant resources and is trending towards the low reserve margin scenarios that Exelon previously forecasted, with potentially significant and highly disruptive consequences for overall reliability.

Although not specifically posed as a question from Commission Staff, it is important to consider the cost implications – on an individual customer and an ERCOT system-wide basis – of continuing under the current ORDC construct, as compared with proposed changes such as an LOLP shift. The current level of resource adequacy and thermal supply additions projected by the CDR is in direct conflict with actual market prices, leaving the Commission with two choices: maintain the current market design and likely fall below the current 11% reserve margin for a number of years, or implement an LOLP shift and maintain approximately an 11% reserve margin by maintaining existing resources and approaching the new-build entrants at the level projected in the CDR. If the Commission does nothing and reserve margins continue to decline and scarcity prices are reached in an increasing number of hours, and possibly increased frequency of involuntary load shed, customers will bear those costs, all the while waiting for new generation to be incented and get built in sufficient quantities to alleviate the stress on the system. A "do nothing" strategy is estimated to cost customers 4x more in average energy costs than an LOLP shift of one standard deviation, without the corresponding reliability benefit. In contrast, although an LOLP shift as recommended by Exelon and others would result in somewhat higher costs than recently experienced during scarcity and near-scarcity intervals, those costs would be less than what customers can expect in the future absent an LOLP shift. In short, with an LOLP shift, customers would ultimately be better off financially, would experience less price volatility, and would have greater assurance with respect to future resource adequacy in the near term, as well as in the longer term.

II. CURRENT SCARCITY PRICING MECHANISM FAILS TO ENSURE BOTH NEAR-TERM AND LONG-TERM RESOURCE ADEQUACY

2. Did the Operating Reserves Demand Curve (ORDC) as currently constituted perform as expected through the summer peak demand period? Were any anomalies observed in the functioning of the ORDC that would indicate a defect in its current implementation?

There was no evidence of a mechanical defect in the operation or implementation of the ORDC throughout the summer peak demand period. However, the purpose of the ORDC is to produce revenues sufficient to ensure long-term resource adequacy, and during the Summer peak demand period with record peak load, record low operating reserves, and significant heat, it failed to do so. See Exelon's Response to Question 1 regarding the need for adjustment to the ORDC to ensure continued resource adequacy.

3. Did the observed levels of capacity, operating reserves, and demand during the summer peak demand period validate or invalidate the estimates contained in the Capacity, Reserves, and Demand (CDR) Report published in December 2017? Please describe in detail any observed variances between the CDR and actual levels of capacity, reserves, and demand.

4. Did the observed levels of capacity, operating reserves, and demand during the summer peak demand period validate or invalidate the estimates contained in the final Seasonal Assessment of Resource Adequacy (SARA) published in April 2018? Please describe in detail any observed variances between the SARA and actual levels of capacity, reserves, and demand.

The observed levels of capacity, operating reserves, and demand during the Summer peak demand period do not invalidate the estimates contained in the CDR published in December 2017 or the SARA published in April 2018. The CDR and SARA are not intended to be, nor can they be, a precise prediction of the actual specific supply resources and conditions during the peak demand period during future years. Rather, they may best be described as a catalog of forward-looking information comprising two principal elements: (1) a periodically-updating report of existing and future capacity resources available to the system over the coming 5 years for the CDR, and the upcoming season for the SARA; and (2) the median of the distribution of potential future peak load. Although the CDR and SARA (collectively, the "Reports") have known limitations, as long as their limitations are recognized and considered, they continue to be a useful informational tool for stakeholders in evaluating supply and demand fundamentals.

The Reports Cannot Predict Inherent Variability

Variability in moving from the Reports' projections to real-time operation comes in two forms: the Reports' inclusion of certain components that are weather-driven or otherwise cannot be predicted with precision, as well as the Reports' exclusion of certain other risks. On the first point, there are a multitude of variables that can take on a wide range of values in actual operation, and factor into resource adequacy risk. Some of the components to the CDR, such as peak load, output of intermittent resources during peak hours, and the availability of DC ties, are central estimates of the weather-driven variables that could take on a wide range of values when moving from forecast to actual operation. Additionally, the CDR does not quantify other key sources of resource adequacy risk, most notably thermal generator outages, that affect the system and customers during the peak hours. Although the SARA adds scenarios around thermal resource outages and peak load, these are random variables that can take on a wide range of outcomes in actual operation.

The reason ERCOT and other markets target, and typically carry, planning reserves well in excess of zero is precisely because of the various random elements such as weather, forced outages, intermittency, etc., that could cause the amount of reserves available to the system during peak hours to vary from the Reports' projected reserves. For the Summer 2018 peak demand hour, the final CDR projection for Summer 2018 was close to the total resources actually available in real-time, in the aggregate, which was largely a function of chance.[7] For the Summer 2018 peak hour, the realized available generator operating reserves were 760 MW higher than the central SARA scenario (and by extension, well in excess of the SARA stress scenario). This outcome was largely due to much lower-than-expected generator outages more than offsetting slightly higher-than-expected load and lower-than-expected total available capacity. This outcome relies on variables, including extraordinary measures taken by generators, that cannot be expected to continue in the future.[8] Given the limitations and intended function of the Reports, this analysis gives no reason to invalidate either one.

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[7] ERCOT, *Supply Analysis Working Group Meeting* presentation, September 14, 2018, slide 17.

[8] Generators took extraordinary measures in order to be available -- including running overnight, deferring critical maintenance, and postponing repair of transmission lines -- which are not sustainable. *Initial Comments of South Texas Electric Cooperative, Inc.*, Project No. 48551, September 14, 2018.

The CDR Does Not Consider Generator Economics

One structural limitation of the CDR projection methodology, however, is that the CDR does not incorporate an economic test when projecting new entry of resources, and mothballs or retirements of existing resources. Rather, in developing such projections, ERCOT relies on the information provided by generators with respect to retirement/mothball plans of existing resources, and progress through the interconnection queue in the case of new builds, to determine whether and when entry and exit actions will take place. Thus, even if a new build is not currently under construction -- and in fact construction is uneconomic -- it will nevertheless be incorporated into the CDR if its progress through the generation queue has reached a certain milestone. Similarly, if an existing resource is uneconomic, it will continue to be incorporated into the CDR projections unless and until the generator owner formally announces plans to retire the resource.

Although ERCOT's approach is understandable, it can lead to significant shifts in the CDR projections as market participants make their plans known. The most recent example of this impacting the Summer 2018 was the announced retirement of over 4 GW of coal generation that occurred between the May 2017 and December 2017 CDRs, which caused the projected reserve margin to drop precipitously, from 18.9% to 9.3%. This coal generation had been known to be uneconomic for several years, but it was retained in the CDR projections until retirements were actually announced. Similarly, as Exelon discussed in its September 14th comments, the current CDR is projecting that a significant amount of uneconomic gas generation will come online through 2022 simply because that generation has advanced far enough through the queue to be counted by the CDR. If this generation were subjected to an economic screen and removed from the CDR, the projected reserve margin for 2019 through 2022 would fall considerably, reaching 6.4% by 2022.[9]

Thus, while the CDR generally accurately reflects the future availability of resources based on the interconnection and availability that resource owners have provided to ERCOT, market participants and policymakers must incorporate their own analysis and judgment with respect to the economic viability of resources when evaluating the likely future accuracy of CDR projections of the resource mix, particularly for the later years in the CDR time horizon.

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[9] *Comments of Exelon Corporation*, Project No. 48551, Sept 14, 2018, at 9.

7. What impact did demand response, including response to potential Four Coincident-Peak days, have on prices or price formation during the summer peak demand period?

Based on the demand response information available at this time, Exelon is unaware what, if any, impact demand response had on prices or price formation during the summer peak demand period. Formal demand response programs are incorporated into the ORDC as available reserves, but there is no in-depth analysis of their capabilities or performance. Greater transparency into demand responses, including their capabilities and performance, would enable ERCOT and the market as a whole to evaluate this question.

Four Coincident-Peak-responsive demand is difficult to predict since it is based solely on individual customer behavior and thus should not be relied upon as a resource adequacy tool; rather, it results from customers reducing their energy usage during what they estimate to be peak hours to minimize their transmission costs. As Exelon discussed in its December 1, 2017 comments filed in Project 47199, the resulting impact on price formation is detrimental to resource adequacy in an energy-only market that relies on scarcity pricing during peak periods to ensure resource adequacy. When load shifts its consumption to avoid or reduce transmission costs, it is not attempting to respond to an energy price signal to reduce demand. This extra incentive to reduce demand alters energy prices during peak periods and the market signals are inefficient as a result. Consequently, potential responsive demand to Four Coincident-Peak days can impact scarcity price formation and therefore undermine resource adequacy.

8. Provide a review of wholesale price formation on each of the following days, including empirical data analysis, narrative commentary, and, where appropriate, identification of policy directives or market rule changes that would improve price formation.

a. July 19, 2018

b. July 23, 2018

c. August 2, 2018

d. Other day(s) of your choosing that you find to be instructive in the analysis of 2018 ERCOT Market Performance.

<u>**Overview**</u>

Although ERCOT met firm load obligations during Summer 2018 with market prices that were not extraordinary higher than in recent years, if any one of a number of uncertain variables on several key summer peak days had turned out differently, ERCOT would have had substantially lower real-time reserves and might have needed to shed firm load. Both temperatures and peak demand were roughly in-line with historical trends; more severe weather patterns, such as those observed in 2011 almost certainly would have resulted in different loss-of-load outcomes.[10] Even in light of this precarious position, there is further evidence that real-time energy prices did not reflect the underlying state of scarcity in the market. The (relatively) low prices experienced in Summer 2018 were not the result of abundant and dependable supply, but rather the result of unexpected surplus capacity from both wind and thermal resources on key days. Adjusting for, or normalizing, thermal generating outages on those key days reveals that market prices in ERCOT remain strongly binary, where the difference between non-scarcity / low prices and scarcity / high prices may be as simple as a single generator outage under the current ORDC market design. This dichotomy, in turn, leads to investor uncertainty and the potential for delayed or avoided new investment.

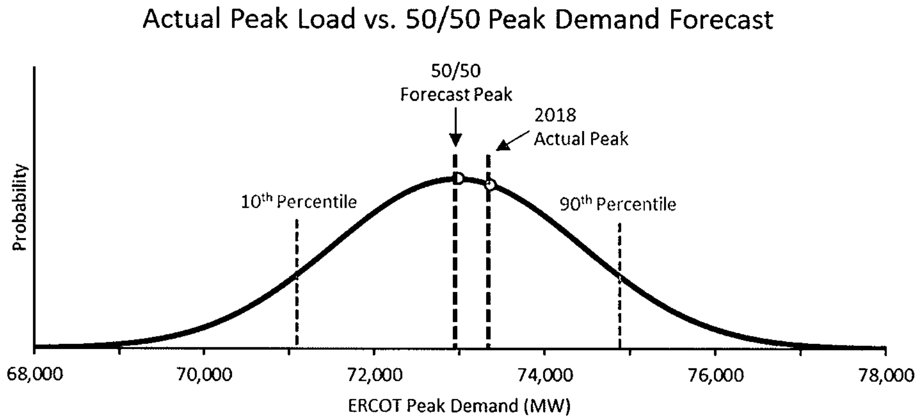
ERCOT experienced peak demand
only marginally above expectations

ERCOT's peak demand for Summer 2018 was slightly above ERCOT's expectations, but not unusually so. The restricted peak demand forecast for 2018 was 72,756 MW[11], while the actual peak demand was 73,364 MW on July 19, 2018, 0.8% higher than forecast. It appears that the observed peak demand was not substantially higher than the 50/50 forecast, and was not particularly high relative to ERCOT's forecast range[12]:

[10] See NorthBridge analytic appendix for a more complete discussion of summer 2018 weather.

[11] "Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2018", ERCOT, April 30, 2018.

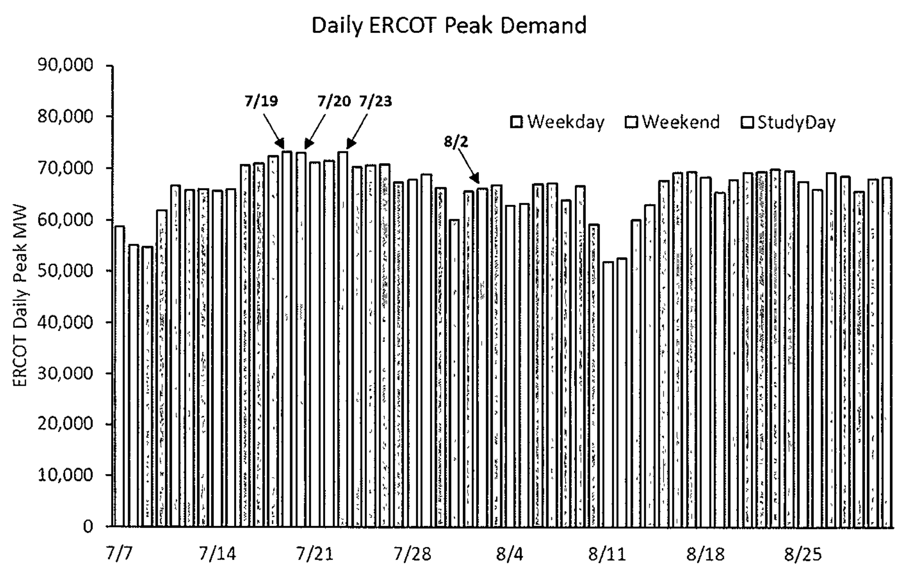
[12] Based on "ERCOT Peak Demand Scenarios", December 13, 2018. ERCOT.



The 2018 peak demand, though above expectations, fell only at the 61st percentile – high, but not exceptionally so. The 90th percentile peak demand forecast published by ERCOT indicates that a peak demand 2,000-3,000 MW higher than what was actually observed would have been well within the forecast range.

ERCOT experienced a brief period of <u>high daily peak demand during late July</u>

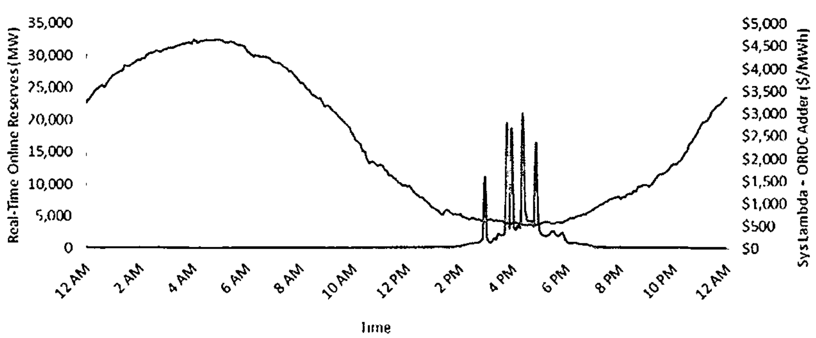
ERCOT experienced a series of high-load days during late July coincident with the late-July heat wave. Although ERCOT typically experiences its summer peak during the first or second week of August, the peak during 2018 was achieved on July 19th.



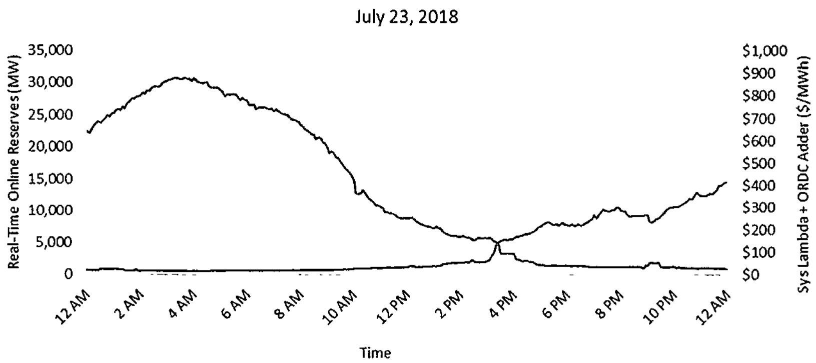
In order to understand the factors that contributed to price formation during summer 2018, we will focus on dissecting four days in detail. July 19, July 23, and July 20 stand out as good candidates as they were the three highest peak demand days in 2018. We also include August 2 at the request of the PUCT. We refer to these four days collectively as the "Study Days."

Scarcity pricing on the Study Days was generally low,
<u>with only isolated pockets of high prices</u>

During the Study Days, ERCOT experienced a small number of SCED intervals in which the on-line ORDC adder was non-trivial. The most prominent example took place on July 19th when the on-line price adder reached $459/MWh and the system lambda + on-line price adder reached over $3000/MWh. This level of scarcity pricing was short-lived, however, as the on-line price adder exceeded $100/MWh for fewer than three hours.



None of the other three Study Days showed comparable levels of scarcity pricing, with the highest on-line price adder being achieved at a level of $38/MWh on July 20th. The sum of the system lambda and on-line price adder only achieved a level of $480/MWh on August 2nd (due to a high system lambda and not due to a meaningful contribution from the ORDC).



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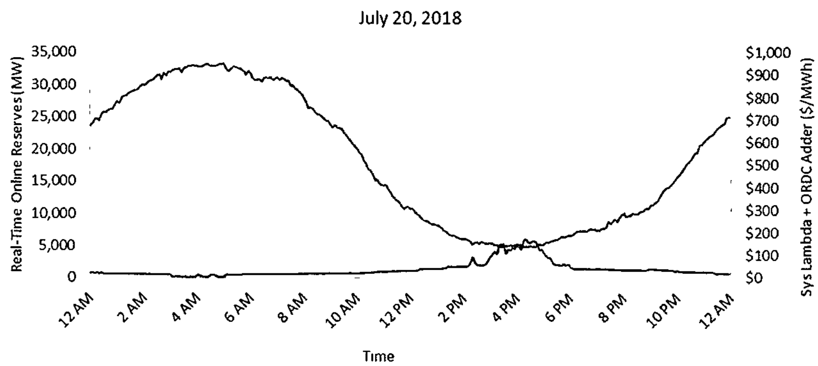
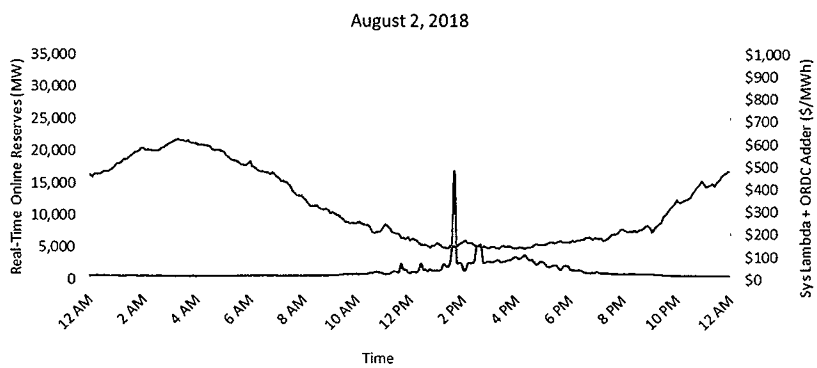
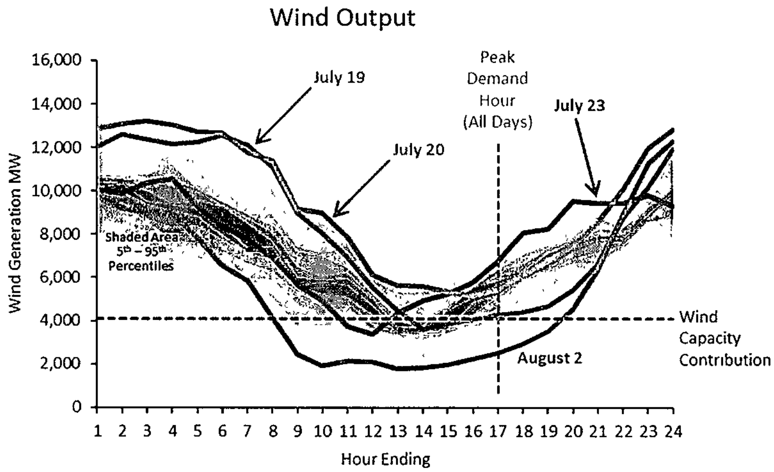


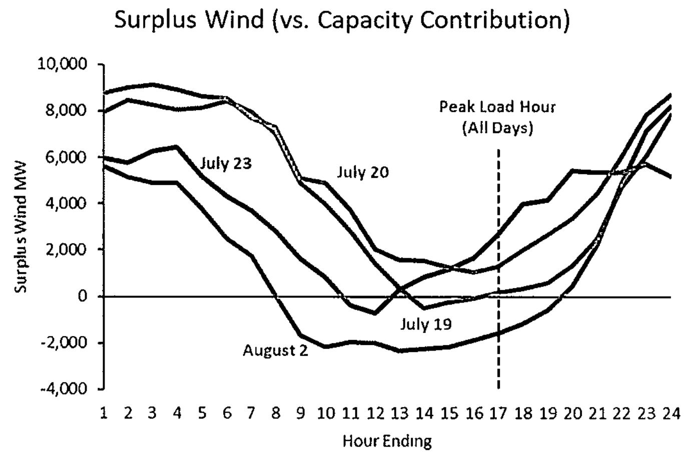


The low level of scarcity pricing on these days was influenced <u>by above-normal wind output and below-normal outages</u>

Scarcity pricing during the Study Days does not appear to have been extreme or persistent despite the high load levels. It appears that unusual/unexpected levels of both wind output (high) and forced outages (low) were contributing factors to this outcome.

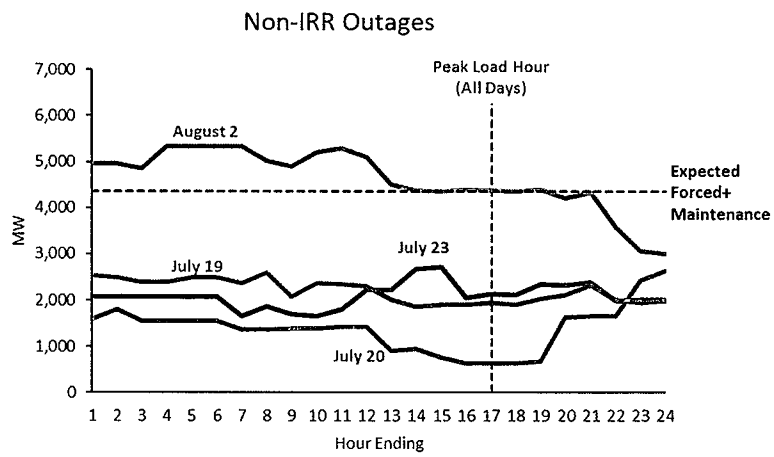
Wind output appears to have exceeded its capacity contribution (14% and 59% of nameplate capacity for non-coastal and coastal wind respectively), as identified in the CDR and SARA reports, during the three highest demand days. Although the hourly wind output levels fell within the historical range, in most hours on the peak days they still represented surplus capacity that had not been included in ERCOT's planning reserve margin calculation. During the peak demand hour, actual wind production exceeded the CDR/SARA capacity contribution by 160 MW, 2640 MW, and 1,300 MW on July 19, July 23, and July 20, respectively. Wind output on August 2 was below its capacity contribution during the peak hour, but the peak demand on that day ranked as only the 35th highest of the year.

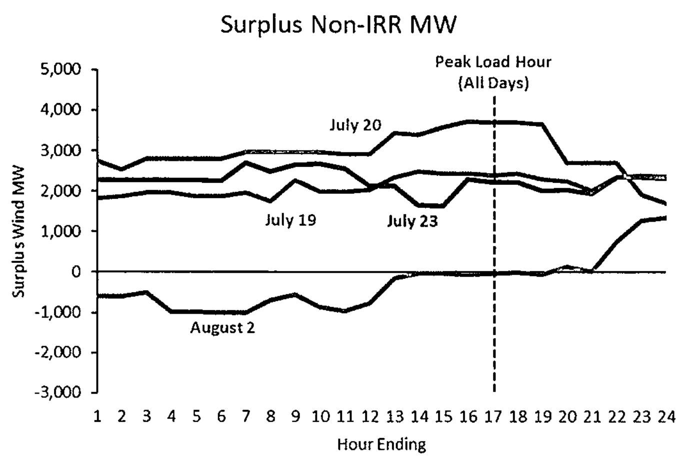




Thermal generating resources, like wind resources, appear to have performed better than expected during the three highest load days. During these days, ERCOT expected to have 4,349 MW of thermal resources on outage – both forced and maintenance.[13] In contrast, on the highest load hour of each of these days, ERCOT actually observed between 636 MW and 2,720 MW of thermal unit outages. As with the wind resources, August 2nd stands out as different. During the peak hour on August 2nd, non-intermittent resources experienced outages at roughly the same rate as assumed in the Final SARA report. However, because August 2nd peak load fell well below the levels seen in the July heatwave (66,225 MW versus the system peak of 73,364 MW), the higher outages and lower wind contribution did not lead to reserve scarcity or particularly elevated prices.

[13] "Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2018", ERCOT, April 30, 2018.

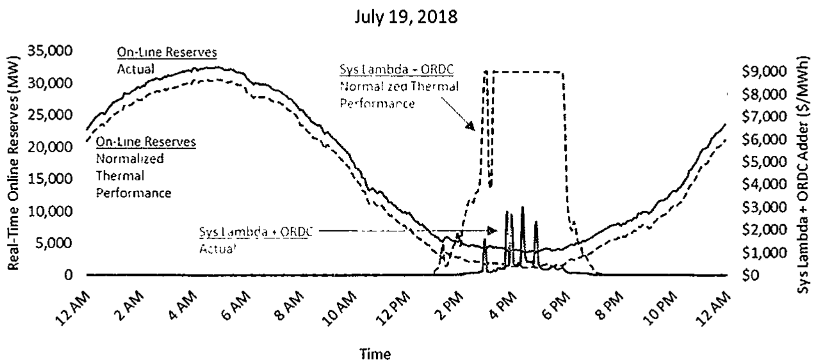


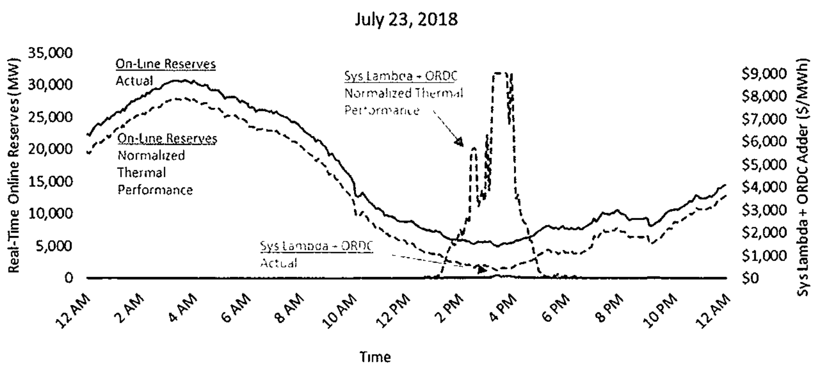


Scarcity pricing would have been higher and
<u>more persistent had generator outages been more typical</u>

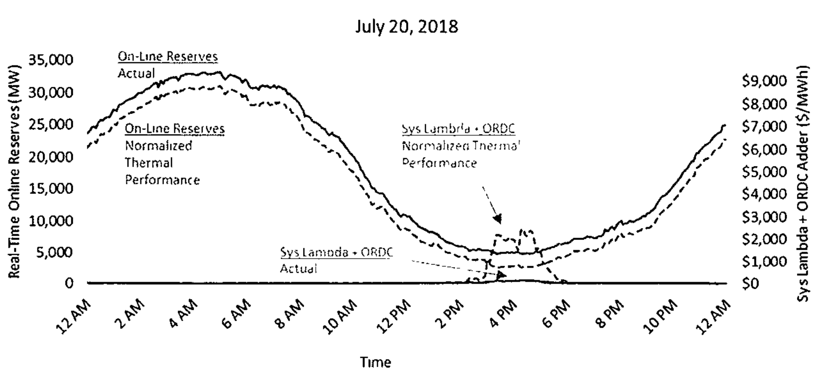
Market price outcomes would have been quite different had thermal performance been more typical. In fact, we can calculate the price impact of more typical thermal fleet performance by removing the surplus MW from the on-line reserve figure used in the ORDC calculation. All else being equal, the ORDC on-line reserve adder would have increased considerably had unexpected non-intermittent capacity not been present. On July 19, the removal of this unexpected capacity would have resulted in real-time prices[14] exceeding $1000/MWh for 5 hours (compared to an actual duration of 25 minutes). Prices would have exceeded $9000/MWh for almost 3 hours. On July 23, the removal of this unexpected capacity would have been similarly dramatic. Instead of zero intervals with the real-time energy price in excess of $1000/MWh, ERCOT would have seen over 3 hours above that level, and 40 minutes at $9000/MWh.

[14] Prices are approximated by adding the system lambda and the on-line ORDC price adder.





Although less dramatic, the removal of unexpected non-intermittent capacity from the ORDC calculation on July 20 would have increased scarcity pricing from being largely trivial, with no SCED intervals exceeding a $40/MWh on-line reserve price adder, to consequential. In this case, real-time energy prices would have topped out at over $2,500/MWh. Total outages on August 2 where generally in line with expectations; scarcity pricing would not have been meaningfully impacted by normalizing thermal outages on that day.



Unexpected surplus capacity from thermal generation during
<u>the highest load days greatly reduced hypothetical CT margin</u>

In the absence of the unexpected surplus capacity from thermal generation, real-time on-line ORDC price adders would have been significantly higher, resulting in real-time LMPs at or near $9,000/MWh. Based on these potential price impacts, we can calculate the lost energy revenues of a hypothetical CT, resulting from actual prices being lower than those implied by normalized thermal outage conditions.

Hypothetical CT Margin with Normalized Thermal Outages

Date	Margin with Prices as Reported ($/KW-YR)	Margin Adjusted for Normalized Thermal Outages ($/KW-YR)	Increase ($/KW-YR)
19-Jul	$1.9	$28.9	$26.9
20-Jul	$0.3	$4.1	$3.8
23-Jul	$0.1	$13.4	$13.3
Total	**$2.3**	**$46.3**	**$44.0**

With prices as reported by ERCOT, a hypothetical CT would have earned just over $2/KW-YR over the course of these three highest load days in summer 2018. If, instead, the prices had reflected normalized thermal outages – as one might have expected – the same resource might have earned an additional $44/KW-YR on those three days alone, over twenty times as much as its actual revenues.[15] This wide swing in actual versus normalized margin has tremendous implications on resource investment and retirement and illustrates the binary nature and high degree of concentrated peak hour risk inherent in the current ORDC design. Actual resource outages are a function both of operator actions, such as planning for or deferring maintenance, and unpredictable random events. Although there is evidence that resource operators took extra action during summer 2018 to ensure that capacity would be online and available during the most critical peak hours, some of the surplus capacity was simply due to good luck, from a reliability perspective.[16] That outcome may have resulted in the loss of energy margin amounting to roughly half of the total Cost of New Entry for a CT resource (roughly $90/KW-YR). Investors cannot possibly predict variables such as the amount of thermal capacity on forced outage, the level of load during the peak period relative to forecast, and the performance of wind generation relative to forecast during a small number of hours during the summer peak. Consequently, they would understandably shy away from taking on the

[15] For comparison, a single hour with a $9000/MWh price contributes almost $9/KW-YR in margin for a Combustion Turbine.

[16] Project No. 48551, "Review of Summer 2018 ERCOT Market Performance, ERCOT's Review of Summer 2018 (June –August)", September 24, 2018, ERCOT. Slide 9.

considerable risk that unexpected swings in these variables during a few critical hours would nullify half or more of the margin needed to support their investment.

III. CUSTOMER COST IMPACT OF AN LOLP SHIFT VERSUS THE STATUS QUO

One way or another, energy costs will rise in the not-too-distant future. As noted by the IMM, "[i]n an energy-only market, shortages play a key role in delivering the net revenues needed to support new investment. Such shortages will tend to be clustered in years with little surplus capacity, unusually high load, or poor generator availability."[17] Given the recent generation retirements and load growth, ERCOT energy prices are going to trend upward. Absent any change to the scarcity pricing mechanism, annual customer energy costs are expected to increase approximately $10-$16 billion per year over 2019-22. In contrast, an LOLP shift of 1.0 would cause annual customer energy costs to rise by about $4 billion per year on average over the same time period,[18] while providing a resource adequacy benefit that is absent in the do-nothing status quo.[19]

When evaluating the customer cost impact of an LOLP shift it is important to distinguish between the short-run and the long-run because the dynamics that drive customer costs and overall reliability are very different in these two periods. The short-run is the immediate three to four years from the present (that is, currently 2019 through 2022) where, due to permitting and construction lead times and other constraints, the supply of available resources to respond to changes in price signals is very limited and discrete and generally restricted to those resources that have been identified in the CDR. Thus, because there is only limited supply available to respond to price signals, both market prices and reserve margins can diverge from their long-run equilibrium levels, potentially by a significant amount. Following the short run is the long-run (roughly 2023 and beyond), where supply is not subject to such constraints and can be expected

[17] *State of the Market Report* (May 2018), xviii.

[18] While this analysis is forward-looking, the impact of an LOLP shift (either 1.0 or 2.0) would have been very similar to the forward-looking values had it been in place during 2018.

[19] The costs of both doing nothing and an LOLP shift reflect NorthBridge's underlying modeling, which features more frequent scarcity and near-scarcity events at a given reserve margin level than Brattle/ERCOT's. If the underlying modeling from Brattle/ERCOT's recent report were utilized in estimating these costs instead of NorthBridge's, it is likely that the estimated cost of both doing nothing and of an LOLP shift (of either 1.0 or 2.0) would both fall, although it is not clear how much or whether the costs of the scenarios relative to one another would change

to fully respond to price signals such that both prices and reserve margins trend towards a long-term equilibrium level. Over the long-run, on average, prices will equal the level needed to incent new entry and no more, and reserve margins on average will be consistent with the economic equilibrium reserve margin associated with the ORDC design. While the dynamics at play in the short-run and long-run are different, a LOLP shift of up to two standard deviations is likely to lead to at most modest cost increases for customers in the long-run, and in the short run is likely to lead to significant net benefits for customers relative to doing nothing.

Exelon's December 2017 comments in Project No. 47199[20] and the accompanying expert report by the NorthBridge Group[21] focused on the long-run customer cost and reliability impact of a LOLP shift of up to two standard deviations and did not assess the potential short-run impacts. This analysis found that the long-run customer cost impact, incremental to doing nothing, of an LOLP shift of either one or two standard deviations was very modest even with a Value of Lost Load ("VOLL") of $9,000 per MWh. With an LOLP shift of 2.0, ERCOT-wide long-run incremental customer costs were less than $80 million per year for the ERCOT market, or approximately 0.3% of total customer billings[22] and with an LOLP shift of 1.0, long-run incremental customer costs were about $25 million per year, or less than 0.1% of customer billings. Further, an LOLP shift actually produced net benefits if one instead were to assume a higher VOLL of $25,000 or $45,000 per MWh, consistent with many economic studies on VOLL.[23] While NorthBridge found the cost impacts to be modest, they found that the more significant impact of the LOLP shift in the long-run is to increase the long-run economic equilibrium reserve margin. NorthBridge's analysis found that an LOLP shift of 1.0 increases the economic equilibrium reserve margin from 11.7% under the status quo ORDC design (assuming CDR levels are achieved) to 13.1%, and a LOLP shift of 2.0 increases the economic equilibrium reserve margin to 15.0%.[24] These increased reserve margins drive improved long-run reliability, with long-run annualized Loss of Load Expectation ("LOLE") falling from 1.4

[20] Project No. 47199, Reply Comments of Exelon Corporation, December 22, 2017. ("December Comments")

[21] The NorthBridge Group, "Economic Equilibrium and Reliability in ERCOT," December 2017. ("NorthBridge Report")

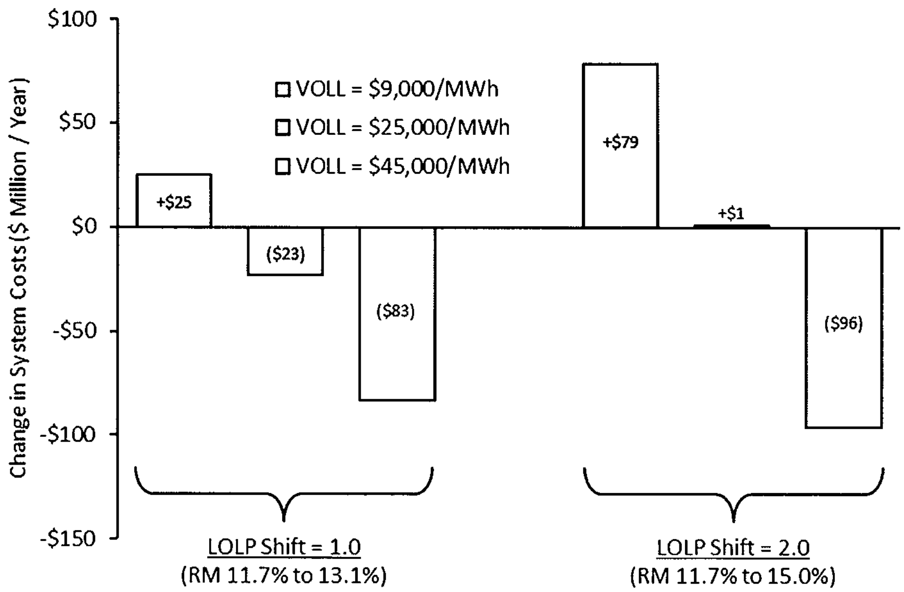
[22] Project No. 47199, Comments of Exelon Corporation, December 1, 2017, p. 23.

[23] See *Estimating the Value of Lost Load, Briefing paper prepared for the Electric Reliability Council of Texas Inc.*, London Economics International LLC, June 17th, 2013, at 9.

[24] NorthBridge Report at 49.

events per year in the status quo (assuming CDR levels are achieved) to 0.8 with an LOLP shift of 1.0 and 0.35 with a shift of 2.0. The chart below summarizes these results:

Incremental Long-Run (i.e. 2023 and beyond) Customer Cost Impact of an LOLP Shift Relative to Doing Nothing



Source: NorthBridge Report, Figure 45.

The reason for the very modest long-run customer cost impact of an LOLP shift is that due to competitive entry of resources in response to price signals, in the long-run the overall level of prices will tend to move toward the approximate level needed to induce new entry and no more, regardless of the precise structure of the ORDC. In the case of an LOLP shift, without any new entry energy prices will initially rise in the short-run because capacity supply cannot fully respond instantly, but over time this increase in prices will attract incremental new entry which will drive market prices back towards the equilibrium level which produces net revenues approximately equal to the Cost of New Entry, and no more. Ultimately, this long-run equilibrium price level will be approximately the same whether or not there is an LOLP shift, but with an LOLP shift additional reserves will enter the market sooner. Thus, the primary long-run impact of an LOLP shift is to drive a higher equilibrium quantity of capacity in the market relative to doing nothing, and thus a higher reserve margin, at approximately the same long-run price level that would prevail under the status quo. The primary incremental cost borne by customers over the long-run is the cost associated with maintaining these incremental reserves.

While customers bear the cost associated with carrying this additional capacity, these costs are offset by the benefits of increased resource adequacy due to additional planning reserves. Because the market will gravitate toward a higher reserve margin with an LOLP shift, customers bear fewer firm load shed events on average over time and scarcity pricing becomes both less common and less severe. When netted against one another, these costs and benefits produce either a very modest net cost, or a net benefit in the long run, depending on the assumed VOLL, as shown in the figure above.

Absent an LOLP Shift, In the Short-Run Customers Risk
<u>Sustained, Frequent Scarcity Pricing Without Resource Adequacy</u>

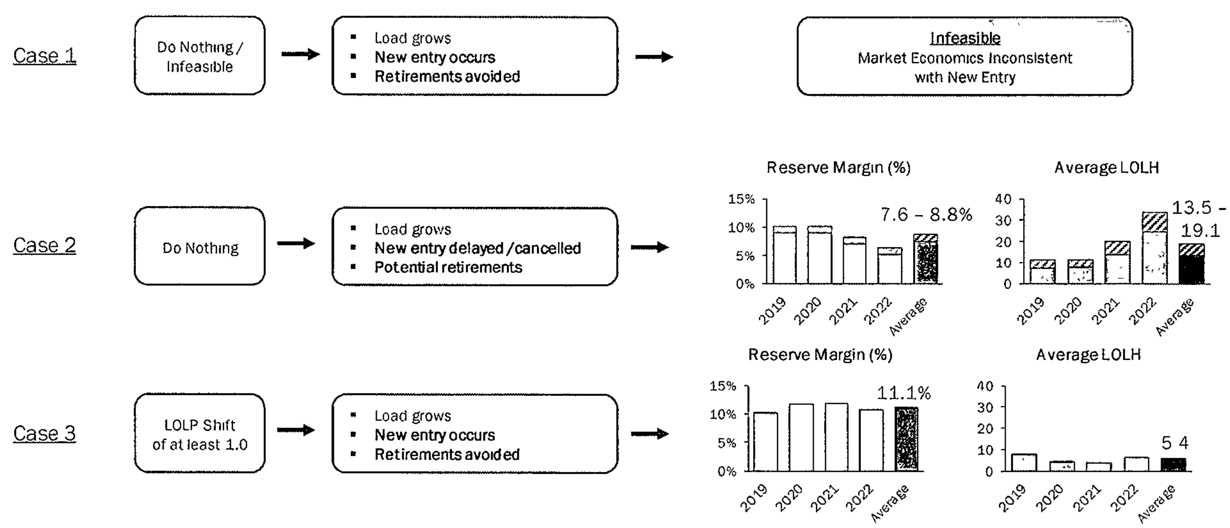
Exelon's initial comments in this proceeding described the particular circumstances facing ERCOT today looking out over the next four years (2019 through 2022), or the short run from the market's current vantage point.[25] The central dilemma faced by ERCOT in the short run is that new entrant capacity is needed over the next four years to meet expected growth and simply maintain reserve margins at the approximate current level, but market prices are currently well below the level needed to both incent this new investment and forestall retirement of existing resources that could cause further deterioration in resource adequacy. Taken together, the apparent "do nothing" status quo represented by current forward market prices and CDR projections of approximately 11% reserve margins going forward appears to be simply inconsistent since the level of new entry necessary to support those reserve margins is not economically feasible given current market price levels. Rather, the more likely "do nothing" status quo is an outcome where the new investment projected by the CDR does not materialize, and reserve margins fall well short of the CDR projections.[26] This scenario results in much more frequent loss of load events, much more frequent and higher scarcity prices, and higher customer costs over the next four years. While these higher prices and more frequent scarcity events would eventually attract new investment and transition the market to long-run equilibrium, because of the limited supply of potential new entrants in the near-term, and the long lead time for physical supply to enter the market, it is likely that these conditions could persist for as long as four years.

[25] See Project No. 48551, Comments of Exelon Corporation, Sept 14, 2018 ("Exelon September Comments").

[26] See Exelon September Comments at 9-12 for a detailed description of this scenario and its implications for reliability.

The alternative approach to the status quo is for ERCOT to implement an LOLP shift of at least one standard deviation. As discussed in Exelon's September 14th comments, if fully reflected in forward prices, such a change would cause energy prices (forward and spot) to shift upward to the point where both new investment in gas resources and retention of existing coal resources is economic looking out over the next four years, and increased entry of renewables and demand response becomes more likely.[27] Under these market conditions, the new investment needed to maintain the approximately 11% reserve margin and achieve the CDR new-build projections is more likely to occur and further retirements are more likely to be avoided and/or some scheduled retirements may be delayed. The recent cancellation of new build gas projects, along with the Oklaunion retirement announcement makes achieving the level projected by the CDR more difficult, but there is likely enough potential for additional entry of renewables, increases in demand response (if documentation is improved), delays or reversals of retirement, and/or expedited entry of gas peakers that achieving the CDR reserve margin of roughly 11% is still feasible if an LOLP shift is implemented promptly.

Thus, in the short-run, there are two discrete options with discrete implications for reserve margins and reliability which are constrained by the limited supply of new builds identified by the CDR. ERCOT can either implement an LOLP shift of at least one and likely maintain the already tight approximately 11% reserve margin level or do nothing and risk considerably lower reserve margins over the next four years. These options are illustrated in the figure below as case 2 and case 3:



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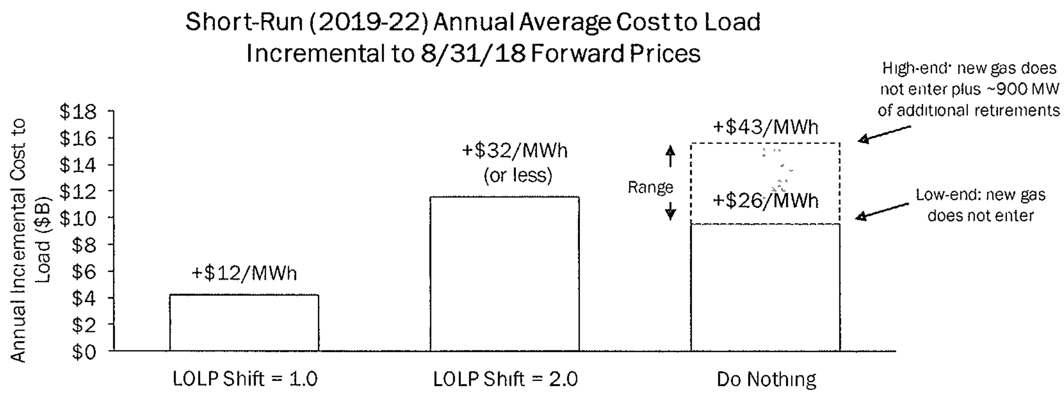
[27] Exelon September Comments at 13-16.

Under both the "do nothing" status quo and under an LOLP shift, customers will bear incremental costs to where markets sit today. These costs include increased frequency and magnitude of scarcity prices, increased loss-of-load events or unserved energy valued at the VOLL, and increased prices during non-scarcity hours. The figure below shows the incremental costs (relative to current market conditions) of the an LOLP shift of either one and two assuming the CDR projected reserve margins are achieved, and the "do nothing" scenario where reserve margins are considerably lower:



(Average during 2019-22)	LOLP Shift = 1.0	LOLP Shift = 2.0	Do Nothing
Planning Reserve Margin (%)	11.2%	11.2% +	7.6% - 8.8%
Loss of Load Events (#/Year)	1.7	1.7 -	3.9 - 5.3
Loss of Load Hours (#/Year)	5.4	5.4 -	13.5 - 19.1
Annual Cost to Load ($B)	+$4	+$12 -	+$10 - $16
Load Weighted Cost ($/MWh)	+$12	+$32 -	+$26 - $43

Source: See NorthBridge analytic appendix.
*Load-weighted cost exceeds impact on around-the-clock wholesale prices because ORDC changes affect high-load intervals. The ATC wholesale price impacts are $7/MWh for an LOLP shift of 1.0, $19/MWh for a LOLP shift of 2.0, and $16 to $26/MWh for the "do nothing" scenario.

Doing nothing is potentially extremely costly both from a financial and reliability perspective over the next four years. Without an LOLP shift, ERCOT risks much higher costs and much reduced reliability. If new entry does not occur and/or additional resources retire over 2019-22, reserve margins will fall considerably below the CDR projections and customers will experience much more frequent scarcity pricing, along with increased instances of firm load shed. If new entry does not occur but there are no incremental retirements, annual costs to load will increase by $10 billion per year, or $26 per MWh on a load-weighted average basis, relative to market prices currently prevalent in the market today.[28] If in addition approximately 900 MW of existing resources retire (of which 650 MW associated with the Oklaunion coal plant has already indicated plans to retire by 2020), annual costs to load will increase by $16 billion per year, or $43 per MWh on a load-weighted average basis.

If an LOLP shift is implemented, in the short term market prices and customer costs will also rise relative to the level of market prices prevalent in the market today, but the impact will be less than doing nothing, and will also result in improved reliability in both the short and long-term. An LOLP shift of 1.0 will cause annual customer energy costs to rise by about $4 billion per year on average over 2019-22,[29] or about $12 per MWh on a load-weighted average basis, or an approximate 14% increase in total customer bills relative to 2017.[30] A LOLP shift of 2.0, will cause annual customer energy costs to rise by $12 billion per year on average over 2019-22, or about $32 per MWh on a load-weighted average basis, an approximate 37% increase in customer bills over 2017. It is likely that the higher prices driven by the larger LOLP shift of 2.0 will cause additional investment of some type beyond that projected in the CDR, although this is difficult to quantify and has thus not been included in this analysis. If this does occur, the customer cost of an LOLP shift of 2.0 will be lower over 2019-22, and reliability will be higher. Compared to the short-term cost of doing nothing, roughly $10 to $16 billion per year over 2019-22, a LOLP shift of 1.0 is considerably less costly for customers by approximately $6 to $12 billion per year, while a LOLP shift of 2.0 would have comparable costs while putting the market on a trajectory to achieve a higher long-run equilibrium reserve margin and thus higher reliability over time.

Summary of Implications Under Do-Nothing or LOLP Shift

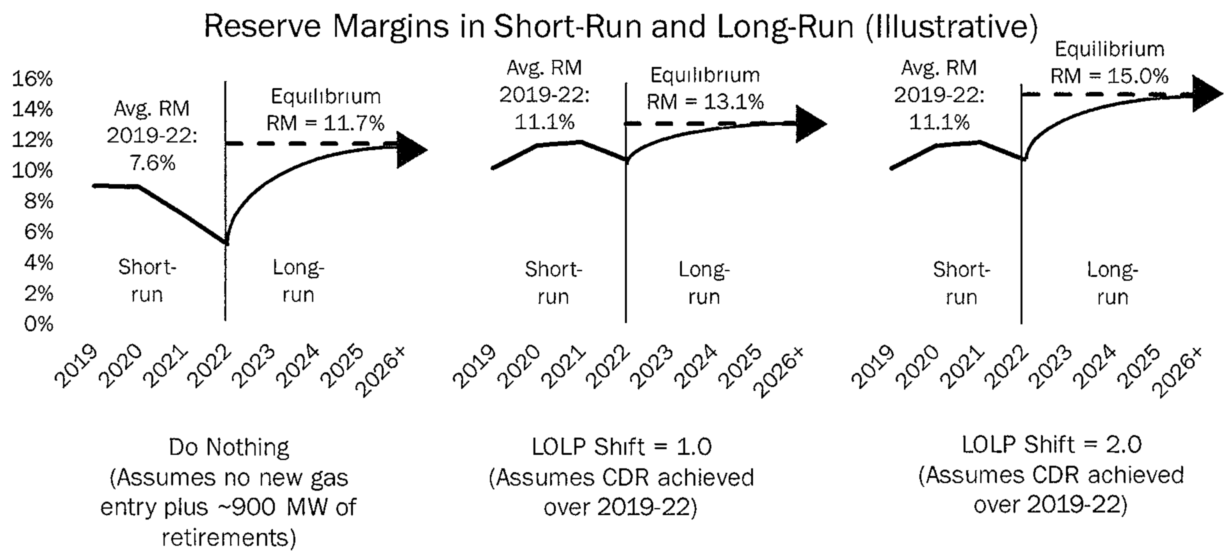
For the longer term, or 2023 and beyond, the market will have more flexibility to add additional capacity beyond that identified in the CDR, and, as discussed above, the impact of an

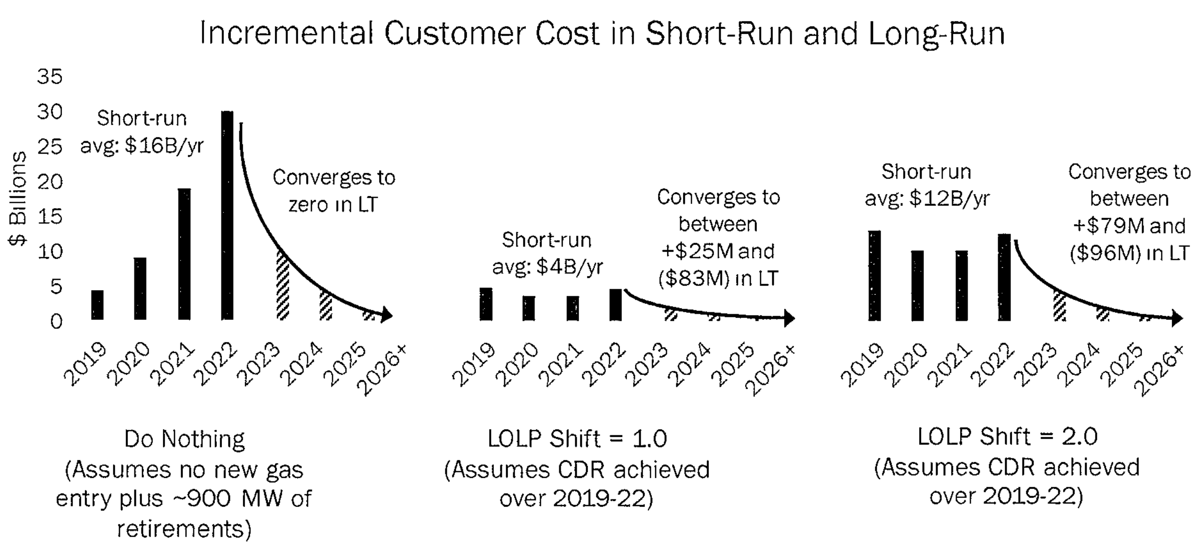
[28] Note that these costs are probability-weighted in that they consider the full forward-looking range of weather and forced outages that drive customer costs associated with scarcity in actual operation. In an extreme weather year these costs could be considerably higher while in a mild year they could be lower. The values reported here reflect the average of all these potential outcomes.

[29] While this analysis is forward-looking, the impact of an LOLP shift (either 1.0 or 2.0) would have been very similar to the forward-looking values had it been in place during 2018.

[30] Based on 2017 average Texas customer bill of $85.5 per MWh (U.S Energy Administration, *Electric Power Monthly, February 2018*, Table 5.6.B).

LOLP shift versus doing nothing will result in a higher long-term equilibrium reserve margin and improved reliability rather than materially higher customer costs. The charts below conceptually summarize the impact of either doing nothing or implementing an LOLP shift on both reserve margins and customer costs as the market evolves through time from the short-run to the long-run:





Source: See NorthBridge analytic appendix. Reserve margin value for 2023+ are based on values estimated in NorthBridge Report from December 2017. Long-term customer costs are from NorthBridge Report (see Figure 45) and show the range assuming VOLL from $9,000 to $45,000/MWh. Customer costs for 2023-25 are illustrative.

In the short-run, doing nothing will likely result in declining reserve margins and rapidly increasing customer costs. Eventually, once prices reach a high enough level and supply has sufficient lead-time to enter, the market will transition towards the long-term, with prices over time converging towards the level consistent with the cost new entry, and reserve margins will trend towards an equilibrium level of 11.7% consistent with the current ORDC design. While an LOLP shift also results in incremental costs in the short-term, it greatly increases the likelihood that the limited menu of supply options that are available in the short-term actually come online, and thus will likely result in a higher short-term reserve margin. Like the do-nothing scenario, the cost increase associated with the LOLP shift will dissipate in the long-term as incremental new entry drives prices back to the level consistent with the Cost of New Entry, but the improved ORDC design in each case will cause the market to trend towards a higher equilibrium reserve margin – 13.1% with an LOLP shift of 1.0 and 15% with an LOLP shift of 2.0. Thus, the overall impact of an LOLP shift is to likely avoid an extreme short-run decline in reserve margins and consequent spike in customer costs and degraded reliability, while driving a higher sustained level of reliability at a very modest cost in the long-run. An LOLP shift also has the additional benefit of decreasing pricing volatility, as discussed in Exelon's September 14th comments.

IV. CONCLUSION AND RECOMMENDATIONS

The ERCOT CDR and SARA reports are important tools in assessing future supply and demand fundamentals, and continue to be useful. However, they are not designed to judge how economics will affect decision-making by generation owners. Nor can they predict what will happen in real-time for weather-related and resource-specific variables that directly affect operating reserves. The Commission must use its judgment regarding the possible outcomes -- including the economic viability of resources -- when using those reports for resource adequacy planning, particularly for years further out in the CDR planning horizon.

Based on extensive analysis demonstrating the insufficiency of revenues produced by the scarcity pricing mechanism, resource adequacy is a concern in both the near-term as well as the long-term, absent meaningful change before Summer 2019. For the reasons stated herein and in Exelon's September 14th comments, Exelon urges the Commission to adjust the ORDC by June 2019 by implementing an LOLP shift of no less than one standard deviation, and by up to two standard deviations to achieve the LOLE that existed when the ORDC was adopted. Adjusting the ORDC will benefit customers and the ERCOT market as a whole, while preserving the integrity of the energy-only construct. Implementation of an LOLP is relatively simple and straightforward, which can and should be accomplished before the next peak demand season of Summer 2019.

October 18, 2018

Respectfully submitted,

_______/s/_____________________________
William Berg
Vice President, Wholesale Market Development
Exelon Corporation
200 Exelon Way
Kennett Square, PA 19348
610-765-6660
William.berg@exeloncorp.com

_______/s/_____________________________
Marka Shaw
Director, Wholesale Market Development
Exelon Corporation
1005 Congress Avenue
Austin, TX 78701
512-391-1962
Marka.shaw@exeloncorp.com

______/s/________________________________
Cynthia Brady
Assistant General Counsel
Exelon Corporation
4300 Winfield Road
Warrenville, IL 60555
630-657-4449
Cynthia.brady@exeloncorp.com

NorthBridge Analytic Appendix

Short-Run Average Annual Cost to Load

We calculated the short-run average annual cost to load by comparing energy charges (i.e., hourly load priced at the LMP) and the cost of unserved energy under four different cases. The four cases differ along two metrics: LOLP shift and forward-looking reserve margin.

Case	LOLP Shift	2019-22 Reserve Margins Average (High/Low)
A	= 1.0	11.2% (10.2% / 11.9%)
B	= 2.0	11.2% (10.2% / 11.9%)
C	= 0.0	8.8% (6.4% / 10.2%)
D	= 0.0	7.6% (5.2% / 9.0%)

We calculated customer costs in each of these four cases using results of the modeling we performed for our December 2017 analysis of ERCOT's ORDC.[1] Using detailed results from the RME™ model, we were able to calculate the expected costs[2] to customers during each forecast year, incorporating both the price impact of modifying the ORDC calculation via an LOLP shift and the overall tightness[3] of the market. The components of customer costs in each case are the sum of three items: i) non-scarcity pricing, ii) scarcity pricing (i.e., resulting from the ORDC), and iii) the cost of unserved energy. For both cases A and B, we calculated each of these three customer cost components using the annual reserve margins identified as "CDR Baseline" in Figure 5 of Exelon's September 14th comments. In case A, hourly energy prices reflected pricing with an LOLP shift equal to 1.0, and in case B hourly energy prices reflected pricing with an LOLP shift of 2.0. Cases C and D represent potential future outcomes without and LOLP shift, but instead incorporate different expectations for annual reserve margins identified as "Thermal new builds do not enter" and "Plus recent mothball return resources retire", respectively, in Figure 5 of Exelon's September 14th comments. We calculated each of the customer cost components for cases C and D using the same detailed RME™ results we used for cases A and B.

The figure titled "Short-Run (2019-22) Annual Average Cost to Load" in Exelon's October 18th comments summaries the differences in these cost outcomes. The bar labeled "LOLP Shift = 1.0" reflects the costs calculated in case A. The bar labeled "LOLP Shift = 2.0" reflects the costs calculated in case B. The bar labeled "Do Nothing" indicates a range of prices, which reflect the costs calculated in cases C and D.[4] The value for all three bars are shown relative to the customers costs we calculate using the reserve margins indicated in cases A and B, but without any corresponding LOLP shift.

[1] "Economic Equilibrium and Reliability in ERCOT", The NorthBridge Group, December 2017.

[2] "Expected" in this context means the average costs across a wide range of potential outcomes. Actual costs in any particular year may be higher or lower than the ex-ante expectation.

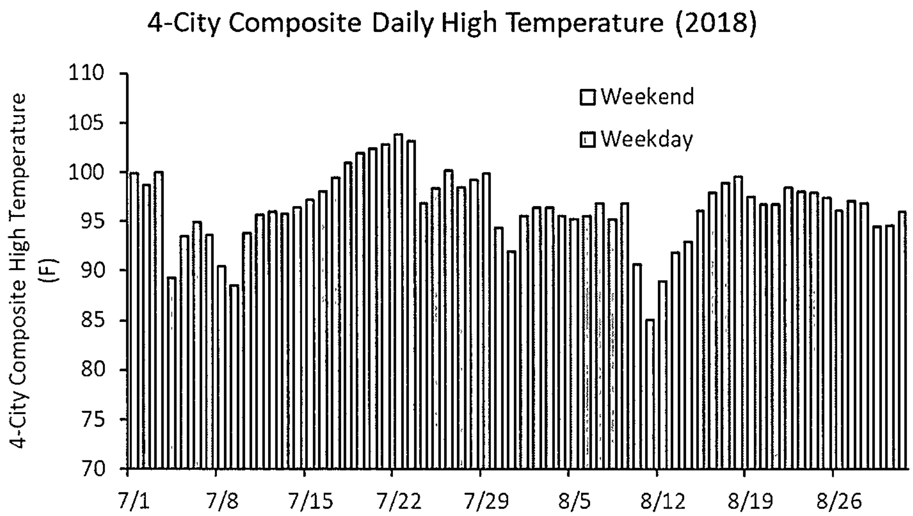
[3] "Tightness" is a general qualitative term that describes the lack of surplus planning reserves.

[4] Case C, with the relatively higher annual reserve margins, is the basis for the low end of the customer cost range. Case D, with the relatively higher annual reserve margins, is the basis for the high end of the customer cost range.

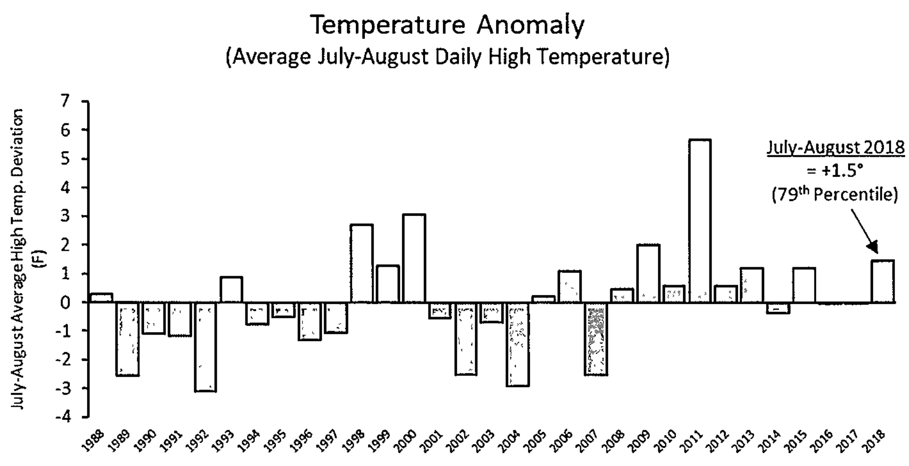
NorthBridge Analytic Appendix (cont'd)

Summer 2018 Weather Analysis

Anecdotally, 2018 was a hot summer in Texas. For example, during July and August Dallas experienced 19 days with a daily high temperature at or above 100 degrees, slightly more than the thirty-year average of 17 days. A late July heat wave also contributed to the general sense that ERCOT was experiencing an above-normal weather year, at least until an unseasonably cool period in August. We have constructed a 4-city composite temperature based on daily observations in Houston, Dallas, San Antonio, and Austin to approximate general weather conditions across ERCOT.[5]



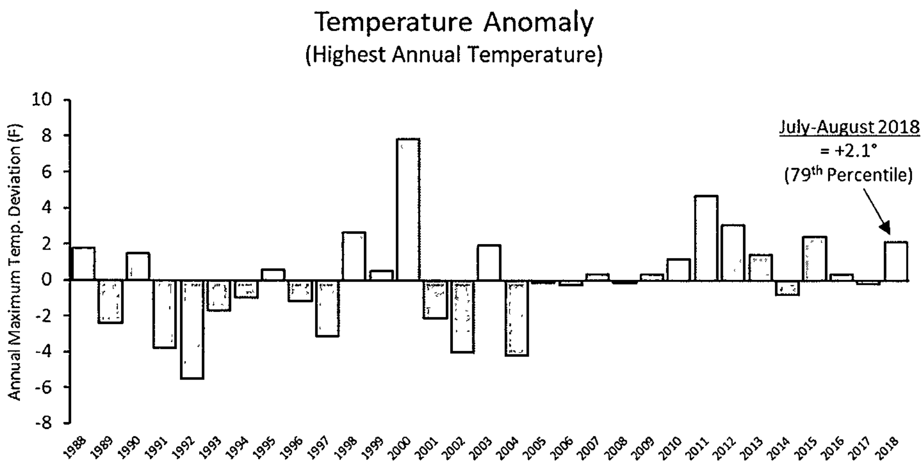
When compared to the prior thirty years, however, July-August 2018 was only moderately warmer, than the thirty-year average (a 79th percentile outcome). Within this sample period, the hottest year by far was 2011, which clearly stands out as unusual. Summer 2018 did not come close to approaching that level of persistent heat.



[5] The composite temperature was constructed by weighting temperatures from each of four metro areas using the following weights: Dallas = 40.8%, Houston = 38.0%, San Antonio = 11.8%, Austin = 9.4%.

NorthBridge Analytic Appendix (cont'd)

While the average July-August temperature for summer 2018 was not atypical, peak demand is more a function of weather conditions on a single day. In terms of peak demand, when compared to the thirty-year average, the hottest day in 2018 does not appear to have been abnormally hot and appears to be closer to ordinary than extraordinary (also a 79th percentile outcome).



Although Dallas did experience extreme heat on several days during July, the high temperatures were not nearly as pervasive across Texas as they were in other, more extreme, years like 2011. On July 22, which fortunately was a Sunday and was only the 5th highest peak demand day of the year, Dallas baked in 109-degree heat, but Houston, San Antonio, and Austin enjoyed cooler temperatures. During the hottest day in 2011, for comparison, high temperatures were comparably high in each metro area.

Hottest Days in 2011 and 2018 (Composite and Metro Area Temperatures)

Year	Date	4-City Composite (F)	Dallas	Houston	San Antonio	Austin
2011	August 27	106.4	106	106	106	110
2018	July 22	103.8	109	98	103	106

Temperatures on Peak Demand Day (Composite and Metro Area Temperatures)

Year	Date	4-City Composite (F)	Dallas	Houston	San Antonio	Austin
2011	August 3	104.5	109	100	102	106
2018	July 19	101.9	108	96	99	103

Each of these observations supports the conclusion that ERCOT experienced what could be described as an ordinary summer from a weather perspective, both in terms of peak period temperature and sustained hot weather over the course of the whole summer and certainly not and extreme year.